ATTACHMENT 2

<u>MEMORANDUM</u>

TO: James Mundt, Director
Office of Fiscal and Management Analysis, Legislative Services Agency

FROM: Janet McCabe, Assistant Commissioner
Office of Air Management

DATE: June 15, 2000

SUBJECT: Analysis of Fiscal Impact of New Rules Concerning Emissions of Nitrogen Oxides; LSA #98-235

The Department of Environmental Management (IDEM) is submitting this draft rule for your economic impact analysis under IC 4-22-2-28, IC 13-14-9-5, and IC 13-14-9-6. The following information is provided for your analysis:

1. The draft rule to be presented to the air pollution control board on August 2, 2000.
2. The estimated economic impact of the August 2, 2000 draft rule on regulated entities.
3. The fiscal impact memo submitted to the State Budget Agency.

I. Background

This rule regulates electricity generating units with a nameplate capacity greater than twenty-five (25) megawatts and industrial, commercial and institutional steam generating units that have a heat input capacity greater than two hundred fifty million (250,000,000) British thermal units (Btu) per hour. It requires these facilities to meet specified nitrogen oxide emission rates during the period May 1 through September 30 beginning in 2003. However, sources can receive one year extension in compliance date upon showing that they have reduced NOx emissions prior to May 1, 2003.

Estimating likely costs associated with this type of rulemaking is difficult and subject to numerous uncertainties. Attempting to calculate indirect costs (in this case, increases in the cost of electricity to residential, industrial and commercial customers) is even more difficult especially in light of the ongoing deregulation of the utility industry, which is substantially changing how the power market functions. However, there are a few critical points to keep in mind.

First, historical experience with other major air pollution rules, the acid rain rules for example, shows that actual costs turn out to be less, sometimes significantly less, than were predicted by either industry or government during the rule development process. Industry groups estimated that the cost of reducing a ton of sulfur dioxide (SO_2) emissions under the traditional regulatory approach at about $1,500 per ton; the EPA's estimate, about $650 per ton. The actual prices of allowances (an allowance equals one ton of SO_2 emissions) available for purchase between 1993 and 1996 at the Chicago Board of Trade, where allowances are traded like commodities, fell from $122 to $66.[1] This disparity is due, at least in part, to the uncertainties inherent in trying to predict future costs and the fact that regulated facilities have been creative in finding cost effective ways to comply with requirements once they are in place. As a result, IDEM believes that estimated costs can only be provided in terms of ranges.

Second, IDEM has built into this draft rule compliance approaches intended to reduce costs. The company-wide averaging option allows affected sources to over control those facilities where it is extremely cost effective and average with other facilities where controls may be very costly. This approach has worked well in other regulatory programs. Also, emissions from low emitting units can be monitored with less expensive alternative procedures that are based on tracking process operations. Therefore, the rule has been revised to allow these units the options to monitor their emissions using CEMs or using alternative procedures.

Third, while the costs in terms of dollars spent is important, just as critical is the cost-effectiveness of this rule compared to other current or possible future clean air programs. The cost effectiveness of reasonably available control measures already implemented in Indiana, tend to be among the less expensive of available controls. Reformulated gasoline is the most expensive program with a cost effectiveness range from $3000 to $5000 per ton. For potential programs that would need to be explored in the event that this rule is not implemented, U. S. EPA has determined that, in general, the cost effectiveness would be approximately $4,300 per ton of VOC or NOx removed. Some examples of these programs are vehicle emission testing, vapor control systems at gasoline pumps, and various industrial controls. IDEM believes that the NOx reductions required by this rule are among the most cost-effective measures available to achieve the air pollution improvement that is required by federal law.

---

[1] Bryner, Gary C., Director Natural Resources Law Center, School of Law, University of Colorado "New Tools for Improving Government Regulation: An Assessment of Emission Trading and Other Market-Based Regulatory Tools", October 1999, page 15.

Lastly, it is important to take note of the costs that will be saved as a result of the air pollution improvements that will be achieved through this rule. Real savings will result from fewer work days lost to illness as well as from decreased health care expenses. The range of cost benefits of ozone and NOx reductions estimated by U. S. EPA for a health and welfare category that includes mortality, hospital admissions for all respiratory illnesses, and worker productivity losses as $27 million to $1, 353 million in 1990 dollars nationally. The agriculture and forestry benefits are estimated to be between $260 million and $574 million, nationally, in 1990 dollars.[2] The air quality benefit of this rule is close to that of the federal NOx SIP Call and it is assumed that other states will reduce NOx emissions similarly.

Factors that may ultimately effect the estimated costs are:

- Selective catalytic reduction systems and selective noncatalytic reduction systems may work better or worse than expected.
- Availability of control and monitoring equipment and experienced labor.
- Future interest rates.
- Future opportunity for a regional trading program which would reduce compliance costs.
- Future regulations by EPA on the NOx SIP Call or the Section 126 petitions.

II. Estimated Economic Impact on Regulated Entities

IDEM has spent considerable time and effort developing these cost estimates. The agency has consulted with other agencies (USEPA, the Indiana Utility Regulatory Commission, the Indiana Office of the Utility Consumer, the State Utility Forecasting Group at Purdue University) and sought and received input from sources included in the draft rule on both IDEM's methodology and cost information for specific companies. The estimating methodology used in this analysis is a "study" estimate with ± 30% accuracy.

The estimated annual cost to regulated entities under this new rule would be associated with:

1. Initial capital costs for installing emission control and monitoring equipment.
2. Annual operation and maintenance costs.
3. Annual administrative costs (monitoring emissions, certifying compliance, modifying permits).

Utilities may recover some or all of these costs through a rate proceeding before the Indiana Utility Regulatory Commission.

Indirect costs are impacts on sectors of the economy that interact with the electricity generating industry and other industries covered by the rule. Households, fuel suppliers, industrial users of electricity, local taxpayers where sources are owned by local governments (schools or municipal combustion units) are

[2] IDEM's draft rule would achieve the vast majority of the air quality benefit of the federal rule, so comparable cost savings would be anticipated.

subject to increased indirect costs. Indirect costs are not estimated in this document, but IDEM worked with the State Utility Forecast Group (SUFG) at Purdue University on estimating impacts on electricity rates. The SUFG report is attached to this analysis as Attachment 4. The report concludes that future average electricity retail rates would be expected to increase four (4) to six (6) percent if NOx emissions are reduced to 0.25 lbs.mmBtu. Additional positive indirect economic impacts would be associated with potential employment impacts (the rule will generate an initial demand for workers to install emission control technology and a continuous demand for workers to operate and maintain the technology), and business opportunities for companies that might be involved assisting regulated sources with compliance activities.

A. Methodology to Estimate NOx Control Costs for Electric Generating Units

In order to estimate the NOx control costs to meet the proposed emission limit equal to 0.25 pounds per million Btu, the number of NOx controls necessary to achieve the needed emission reductions from baseline emissions was estimated. The needed emission reductions for each utility were estimated using its 2007 projected heat inputs and baseline emission rates equal to the lowest of the actual or the Title IV allowable emissions. Several assumptions related to the types of control equipment likely to be used and their efficiencies were made in addition to the assumptions that the proposed emission limit will be achieved on a system-wide average basis by controlling units that will be more cost effective to control.

The NOx emissions can be controlled mainly by two types of control methods, combustion modification controls and flue gas treatment controls. Combustion modification controls reduce NOx emissions by modifying combustion conditions such as combustion zone oxygen levels and temperatures and include low excess air, low NOx burners, over-fire air, and flue gas recirculation. However, not all of these control technologies are applicable to or effective in reducing NOx emissions from all boiler designs. Flue gas treatment controls, selective catalytic control systems (SCRs) and selective non-catalytic control systems (SNCRs), remove NOx emissions from the flue gas after it is formed by injecting ammonia or urea into the flue gas streams. Combustion controls and SNCRs are generally cheaper than SCRs.

It is estimated that compliance with a 0.25 pounds per million Btu emission limit would require significant overall emission reductions beyond those already required by Title IV of the Clean Air Act (acid rain requirements). In order to comply with the Title IV limits, utilities would have used most of the available combustion control options. A telephone survey of the utilities indicated that fuel switching (switching from combusting coal to gas, for example) is not likely to be an emissions reduction option. Therefore, the cost analysis assumed the application of SCRs and SNCRs. The cost estimate also considered the application of burner tuning and combustion optimization (combustion control measures which provide cheaper emission reductions) in addition to SCRs or SNCRs where utilities indicated that these controls could be applied to their units. Combustion control measures provide cheaper emission reductions and SNCRs are less expensive than SCRs, but SCRs are more efficient in reducing NOx emissions. SNCR experience on large units is very limited. It is generally cheaper on a dollar per ton of NOx removed basis to control high NOx emitting units (units with large capacities, high baseline emission rates, and high capacity factors). Therefore, cost estimates assumed controls on units that will yield a lower cost effectiveness ratio (costs of controls divided by the number of tons of NOx reduced).

The NOx control costs for electric generating units include total capital costs, fixed and variable operation and maintenance costs, and cost effectiveness in dollars per ton of NOx removed. A number of assumptions were made regarding the control equipment effectiveness, economic factors and retrofit requirements. The total ozone season costs are annualized capital costs plus fixed and variable operation and maintenance costs. The ozone season cost effectiveness is dollars per ton equal to total ozone season costs divided by the total ozone season tons of NOx removed. The cost estimates are in 1998 dollars as most utilities provided cost estimates in 1998 dollars. It must be noted that at the time of these estimates, utilities were estimating the economic impact of U. S. EPA's NOx SIP Call on their facilities; while some estimates were based on rigorous engineering estimates (project control or definitive) and may be within ±10% error margin, others were scope or order of magnitude estimates with ±20% to 30% margin of error. It is estimated that twenty (20) to thirty (30) selective catalytic reduction (SCR) system controls and seven (7) to nine (9) selective noncatalytic reduction (SNCR) system controls will be needed to meet a system-wide emission rate of twenty-five hundredths (0.25) pound of NOx emitted per million Btu heat input from ten utilities with ninety four (94) units capable of generating greater than 25 Megawatts of electric output. The range of costs is based on the following scenarios from the lowest costs to the highest costs:

1. This scenario used SNCR control efficiency up to 60% and SCR efficiency equal to 70% to 80% and a retrofit factor and an economic factor to amortize capital cost the same for all. The SCR retrofit factor was assumed to be 1.34 but may vary between 1.02 and 1.52 and the economic factor was based on a discount rate equal to 7% and economic life of control equipment equal to 15 years. The costs analysis used U. S. EPA Alternative Control Techniques Document and data from U. S. EPA 2007 projected emissions inventory.
2. This estimation is the first scenario but assumed SNCR efficiency equal to 30% and SCR efficiency equal to 80% based on input from utilities and field studies.
3. This estimation is the second scenario but with adjusted heat inputs and emission rates provided by the utilities which result in higher baseline emissions. In addition, several utilities provided cost estimates based on source specific evaluations by engineering firms specializing in the design and construction of control equipment. These utilities also provided economic factors specific to their situations. For other utilities, an economic factor based on a discount rate equal to 7% and economic life of control equipment equal to 15 years was used.
4. This estimation is the same as the third scenario but with a 10% planning margin. The 10% planning margin takes into account extra control requirements to account for daily variations in utility operations, such as start-ups, shut-downs and outages and any costs associated with complying with a thirty (30) day rolling average.

B. Estimated Costs for Electric Generating Units

The cost estimating scenarios are estimated to meet the 0.25 pounds per million Btu emission rate, which will achieve reduction of 72,634 to 92,614 tons of NOx per ozone season from the following electricity steam generating unit companies:

American Electric Power	6 units
Cinergy	27 units
Hoosier Energy	4 units
Indiana-Kentucky Electric Company	6 units
Indiana Municipal Power Agency	4 units[3]
Indianapolis Power & Light	17 units
Northern Indiana Public Service Company	17 units
Richmond Power & Light	2 units
Southern Company	2 units
Southern Indiana Gas & Electric Company	9 units

The rule requires NOx emissions monitoring using continuous emissions monitoring systems (CEMS) or alternative monitoring methods as applicable. A number of electric generating units presently monitor their NOx emissions using CEMS. No increase in monitoring costs at the existing CEMS units is assumed. No additional CEMS are assumed.

As shown in Table 1 and using the four scenarios explained above, the range of overall cost of reducing 72,634 to 92,614 tons of nitrogen oxides during the ozone season from May 1st to September 30th on a company-wide basis in 1998 dollars is:

Capital costs for control equipment: $716 million to $1.18 billion.

Annualized capital cost and ozone season operation and maintenance costs for control equipment: $134 million to $207 million.

Based on these cost estimates, the overall cost effectiveness of the draft rule ranges between $1,845 to $2,235 per ton of nitrogen oxides reduced. The estimated cost effectiveness for individual utilities varies between $835 to $4,342 per ton.

C. Methodology to Estimate NOx Control Costs for the Industrial, Commercial, and Institutional (ICI) Units

The rule proposes to limit emissions from industrial, commercial, and institutional units at different rates depending on the unit types and fuel types, coal, oil and gas. The permit records were used to identify

[3] Emission rates are estimated to be below the draft rule emission limits and are not shown in Table 1.

potentially affected units and 1996 Aerometric Information Retrieval System/AIRS Facility Subsystem (AIRS/AFS) data were used to estimate the tons of ozone season NOx removed. The 2007 projected NOx emissions from these units are estimated at 11,696 tons compared to 145,175 tons from electric generating units. Therefore, the proposed emission limits for these units assume relatively cheaper combustion modification controls and SNCR controls. In addition to the NOx reduction costs, these units will also incur continuous emissions monitoring costs. The rule requires continuous monitoring of emissions from coal-fired units and monitoring of emissions from other units using alternative methods as applicable. Currently, nine affected units monitor their NOx emissions using CEMS. No additional cost of monitoring at these units is assumed. However, it is estimated that three (3) additional CEMS will be needed. This estimate is based on the unit-stack configuration.

The estimated costs of the draft rule for the industrial, commercial, and institutional (ICI) units include the cost of NOx controls and the costs of measuring NOx emissions using CEMS. The NOx control capital and operation and maintenance costs for the affected units were estimated using unit-specific data such as design heat input capacities and capacity factors. The capital costs were annualized using a control equipment life of ten (10) years and an amortization rate equal to 10%. The economic life of combustion modification controls is estimated as 10 years as compared to 15 to 20 years for flue gas treatment controls (SCRs and SNCRs). The total annualized capital costs and the ozone season operating and maintenance costs were used to estimate the cost per ton of NOx removed. U.S. EPA estimates the annual cost of continuous emission monitoring equal to $32,300 in 1990 dollars.[4] The EPA Alternative Control Techniques Document-NOx Emissions from Industrial/Commercial/Institutional Boilers, March 1994, was used to estimate costs. The costs in the EPA document are in 1992 dollars. The NOx control costs and emissions monitoring costs were adjusted to 1998 dollars using estimated 1990/1998 and 1992/1998 inflation factors equal to 1.16 and 1.114, respectively. The inflation factors were estimated using references such as Gross Domestic Product Implicit Price Deflator Index, Chemical Engineering Plant Cost Index, and Marshall & Swift Equipment Cost Index. The cost estimates do not include ICI units known to be shut down after 1996.

D. Industrial, Commercial, and Institutional Steam Generating Units

It is estimated that the draft rule will result in reduction of 4,405 tons of NOx per ozone season from the projected 2007 emissions from the following industrial, commercial, and institutional steam generating unit entities:

Alcoa

[4]Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions, Office of Air Quality Planning and Standards, Office of Atmospheric Programs, U. S. Environmental Protection Agency, September 1998, page 7-14.

Amoco-Whiting
Bethlehem Steel[5]
Inland Steel
Indianapolis Power & Light
LTV Steel
New Energy Corporation
U. S. Steel[5]

As shown in Table 2 in 1992 dollars, the estimated cost of compliance with this draft rule for thirty one (31) industrial, commercial, and institutional steam generating units in 1998 dollars is:

Capital cost for control equipment: $75 million to $83 million.
Annualized capital cost for control equipment: $12.3 million to $13.6 million.
Ozone season operation and maintenance costs: $1.66 million to $1.83 million.
Total ozone season cost: $14 million to $15.4 million.
Capital start-up costs for continuous monitoring equipment for three (3) stacks:
$0.5 million to $ 0.6 million
Annual costs (monitoring, reporting, and permitting) cost: $112,000 to $124,000

Based on these cost estimates, overall (control equipment and CEMS) cost effectiveness of the draft rule is $3,206 to $3,527 per ton of nitrogen oxides reduced. The upper end of the range accounts for a 10% planning margin.

One entity with six boilers and six stacks estimated that installation costs for continuous emission monitoring would be $1.5 million based on recent CEM experience with sinter plant CEMS and annual operating and maintenance costs of about $600,000 per year or $100,000 per CEM.

III. Summary

The estimated average cost effectiveness is $1,845 to $2,235 per ton of NOx reduced from electric generating units and $3,206 to $3,527 per ton of NOx reduced from industrial, commercial, and institutional steam generating units.

IV. Governmental Entities

There are no unfunded mandates placed upon any state or local agencies by this draft rule.

V. Information Sources

[5]Actual emissions are below the draft rule limits and are not included in Table 2.

Aerometric Information Retrieval System/AIRS Facility Subsystem (AIRS/AFS)
Alternative Control Techniques Document-NOx Emissions from Industrial/Commercial/Institutional Boilers, EPA-453/R-94-022, March 1994.
Alternative Control Techniques Document-NOx Emissions from Utility Boilers, EPA-453/R-94-023, March 1994.
Analyzing Electric Power Generation under the Clean Air Act, March 1998
Bryner, Gary C., Director Natural Resources Law Center, School of Law, University of Colorado "New Tools for Improving Government Regulation: An Assessment of Emission Trading and Other Market-Based Regulatory Tools", October 1999, page 15.
Chemical Engineering Plant Cost Index
Comment from company with ICI units
Electric Power Research Institute
Engineering studies provided by six utilities
Gross Domestic Product Implicit Price Deflator Index
Indiana Utility Regulatory Commission
Indiana Office of Consumer Counselor
Marshall & Swift Equipment Cost Index
Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions, Volume 1: Costs and Economic Impacts, EPA-452/R-98-003, September, 1998.
Regulatory Impact Analysis for the NOx SIP Call, FIP, and Section 126 Petitions, Volume 2: Health and Welfare Benefits, EPA-452/R-98-003, December 1998.
State Utility Forecasting Group at Purdue University

If you have any questions concerning this economic impact analysis, please contact Jean Beauchamp, Office of Air Management, Rules Development Section, at 232-8424.